

Article

Global Hydrogen and Synfuel Exchanges in an Emission-Free Energy System

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Abstract: This study investigates the global allocation of hydrogen and synfuels in order to achieve the well below 2 °C, preferably 1.5 °C target set in the Paris Agreement. For this purpose, TIMES Integrated Assessment Model (TIAM), a global energy system model is used. In order to investigate global hydrogen and synfuel flows, cost potential curves are aggregated and implemented into TIAM, as well as demand technologies for the end use sectors. Furthermore, hydrogen and synfuel trades are established using liquid hydrogen transport (LH₂), and both new and existing technologies for synfuels are implemented. To represent a wide range of possible future events, four different scenarios are considered with different characteristics of climate and security of supply policies. The results show that in the case of climate policy, the renewable energies need tremendous expansion. The final energy consumption is shifting towards the direct use of electricity, while certain demand technologies (e.g., aviation and international shipping) require hydrogen and synfuels for full decarbonization. Due to different security of supply policies, the global allocation of hydrogen and synfuel production and exports is shifting, while the 1.5 °C target remains feasible in the different climate policy scenarios. Considering climate policy, Middle East Asia is the preferred region for hydrogen export. For synfuel production, several regions are competitive, including Middle East Asia, Mexico, Africa, South America and Australia. In the case of security of supply policies, Middle East Asia is sharing the export volume with Africa, while only minor changes can be seen in the synfuel supply.

Keywords: hydrogen; energy system; synfuels; E-fuels; ETSAP-TIAM; TIMES; LH₂; PtL



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1. Introduction

In the Paris Agreement [1], the states of the world agreed to limit global warming well below 2 °C, preferably to 1.5 °C. The 2018 published IPCC report [2] advertised that this would mean a net global CO₂ budget of 420 Gt, with the best likelihood to prevent exceeding the 1.5 °C target. Over the last decades, the global gross CO₂ emissions were rising continuously. In 2022, the global gross CO₂ emissions were recorded at roughly 36 Gt [3]. Maintaining the status quo would lead to exceeding the Paris Agreement goals in less than 15 years. To follow the agreement, more climate policy must be implemented and innovative mitigation plans applied.

To achieve a tremendous reduction in CO₂ emissions and reaching net zero all sectors must be decarbonized. Decarbonizing the power sector is common practice. Renewable energies have proven to be cost-competitive compared to fossil fuel power generation; even countries without climate policy are installing renewable potentials [4]. Despite the trend towards electrification in all sectors, there are certain technologies that still rely on

fossil energy carriers. Fortunately, hydrogen and synfuels are suitable to fill this gap, although both energy carriers are likely to be more expensive than the fossil competitors, if externalities are not accounted for. To enter hydrogen and synfuels into energy systems, climate policies like carbon price or subsidies need to be applied.

In 2019, the European Union (EU) announced the Green New Deal [5]. In addition to the determination of carbon reduction goals and greenhouse gas neutrality by 2050, it was also announced to boost the hydrogen economy. In parallel, Germany has set its own tight goals with the agreement on net zero by 2045 [6]. As Germany's gross domestic product (GDP) heavily relies on its partly difficult to decarbonize industry, hydrogen and synfuels will most likely play a crucial role to achieve this goal.

In 2022, the US passed the Inflation Reduction Act (IRA) [7], making the decision to sustainably strengthen the hydrogen economy. In addition to the members of the EU and the US, many other countries entered or already pursued the plan to build up a hydrogen economy. Therefore, it is necessary to expand renewable energy generation technologies as hydrogen and synfuels rely on electricity for electrolysis and the Fischer–Tropsch processes.

This analysis deals with the question of the available technology transformation pathways of the global energy system in order to achieve the 1.5 °C target set in the Paris Agreement. To fulfill that target, hydrogen and synfuels are required to fill the gap of today's oil and gas technologies and lead to a sustainable transformation within the energy system. Furthermore, this analysis is questioning the exchanges of hydrogen and synfuels across regions in a cost-optimal transformation pathway. Therefore, the global energy system model TIAM is used. There are several conceivable ways to produce hydrogen, for example, via fossil energy carriers (grey hydrogen). If carbon capture and storage (CCS) is combined with fossil energy carriers, the hydrogen is labeled as blue hydrogen. If the electricity comes from nuclear power, the hydrogen is considered pink. In this study, only green hydrogen and synfuels resulting of green hydrogen are considered. Hydrogen and synfuels are regionally aggregated and implemented into TIAM. Renewable energy production is limited by the available potential, and therefore, the use of electricity for direct electric use, hydrogen and synfuel production is investigated. Four different scenarios are implemented to cover possible future events, including no climate policy, climate policies and different characteristics of security of supply. Due to the different scenarios, the results and possible pathways towards an emission-free energy system are concluded and discussed.

2. Literature Review

Previous work was done in the analysis of the future production costs of synfuels and hydrogen based on the generation technologies themselves, the availability of cheap variable electricity generation costs based on the availability of renewable electricity generation and the transport and worldwide trade of emission-free energy carriers.

The production costs of synfuels and hydrogen are discussed in Agora [8]. Therefore, wind offshore is the most expensive option, whereas photovoltaics (PV) seems to be the cheapest, especially in Africa and the Near East. Geothermal could also be an option, but the global potentials are rather small. Hydrogen imports are cheaper than local production in Europe, as the results show. In a total comparison of hydrogen production, Nikolaidis and Poullikkas [9] have concluded that steam methane reforming (SMR) is the cheapest option. Overall CO₂ prices are not considered as well as a carbon budget. Schmidt et al. [10] investigated the production route of synfuels by using renewable energies. According to the results, the source of carbon has a huge impact on the costs. Using direct air capture (DAC) technology, synfuels costs are reported at 42 EUR/GJ, whereas synfuels costs using concentrated CO₂ by using carbon capture use and storage (CCUS) are referred to as 31.3 EUR/GJ. High temperature electrolysis is applied for both routes. Fasihi et al. [11] investigated the production chain of synfuels in several regions. Beneficial regions are Africa, South America, Asia and Australia. Production costs start at 79 USD/barrel and grow to a maximum of 135 USD/barrel. The costs are highly sensitive to certain factors,

e.g., left-over oxygen for sale or waste heat recovery. Chapman et al. [12] investigated the production in Australia in three different locations for the trade of hydrogen with Japan, in order to replace remaining coal trades. Currently, hydrogen production with coal gasification and CCS is cheapest, but in the long term renewable electricity and water electrolysis could lead to lower costs of hydrogen production. Rosen et al. [13] discussed the importance of hydrogen technologies in the energy system. They also considered rising demand, and showed via the literature analysis that hydrogen could be supplied in the future for as low as 1.7 USD/kg. In 2017, Fasihi et al. [14] published another study, which calculated the production costs of synfuels considering the whole production chain in the Maghreb states. The study resulted in diesel and kerosene prices of 88 EUR/MWh in 2030 and 83 EUR/MWh in 2040. Libya has the best potential in the Maghreb states. In 2021, Ueckerdt et al. [15] investigated the production of synfuels. Transport from Africa to Germany was also considered. They concluded that mitigation costs could be in the range of 19–267 EUR/t_{CO2} in 2050. In 2018, Blanco et al. [16] investigated the hydrogen demand using the JRC, a European model. According to their findings, the hydrogen demand could rise to 20–120 Mt/a. It would mostly be used for synfuel production and transport, as well as for industry purposes. As far as CCS is not an option, electrolysis is the favored production route for hydrogen. If policy-makers allow CCS, SMR would be the choice of hydrogen production.

In addition to the costs of hydrogen and synfuels, the question of suitable supranational transport is essential. An analysis with the JRC model [17] indicated that for short distances, pipelines are the best choice, and for distances between 3000 and 16,000 km, LH₂ compared to the transport of hydrogen via LH₂, ammonia and LOHC is the favored choice. The report by IRENA [18] showed that LH₂ is cheapest below 5000 km. Overall, it strongly depends on the capacities transported in the long term.

Furthermore, there are studies that combine both aspects of the costs of hydrogen and synfuels as well as transport options in one model. A report by EWI [19] compared 94 countries in 6 continents on producing hydrogen. Starting from 2030, hydrogen production by electrolysis could become cost-competitive to SMR. The cheapest option is PV in sun-rich countries, whereas wind offshore is reported as the most expensive route. In the case of transport, LH₂ is the favored choice for distances longer than 7000 km. In contrast, Niemann et al. [20] came to a fairly different result. While LH₂ is a good option, LOHC was cheapest due to the reason of energy losses during transport and storage. However, a report by the German Aerospace Center [21] showed, too, that LH₂ transport is the cost-minimal way of hydrogen transport starting in 2030 compared to LOHC and other carriers. Gallardo et al. [22] investigated the production of hydrogen via concentrated solar power (CSP) and PV, as well as the transport via ammonia or LH₂. Production via PV resulted in being the cheaper choice, while ammonia could have advantages if used as the end product. In 2025, ammonia will have a production cost of 3.94 USD/kg whereas liquid hydrogen is reported as 4.89 USD/kg. Wijayanta et al. [23] had a similar approach. They also concluded that ammonia is cheapest if used as the end demand product. Otherwise, LH₂ could become cheaper in 2050 if hydrogen is demanded. Furthermore, LOHC was investigated as well, which has shown to be the overall most expensive option. Ishimoto et al. [24] studied the pathways of hydrogen production and hydrogen carrier transport from Norway to Japan. Results show that hydrogen production via autothermal reforming (ATR) and ammonia production via SMR are the cheapest. As far as hydrogen is demanded, LH₂ is the best transport option. If ammonia is demanded as an end use product, the transport of ammonia is cheaper in comparison to hydrogen. In Stiller et al. [25], the route of hydrogen production in Norway was analyzed. The levelized costs of electricity from wind energy are reported as 9.6–10.4 Ct/KWh. For the transport of hydrogen to Germany, LH₂ was proposed with costs starting at 11.4 Ct/KWh. Kamiya et al. [26] analyzed the hydrogen pathway from Australia to Japan via LH₂. The production route was via lignite and CCS. Fraunhofer IWES [27] conducted an analysis of the hydrogen production globally, based on the global wind atlas. It showed that Africa has

a low cost of production and is exporting hydrogen to Europe, which has higher costs of production. Teichmann et al. [28] share the same result. Furthermore, they concluded that high voltage direct current (HVDC) could also be an option instead of hydrogen export. Heuser et al. [29] discussed the production of hydrogen via onshore wind and PV with liquid hydrogen transport pathways afterwards, and showed that Europe imports hydrogen from Africa. In a study by adelphi et al. [30], the political and economic frameworks are discussed for hydrogen export to Europe. The study concluded that Norway and Morocco are the best choices as they both offer hydrogen for low costs, while also being politically stable.

Several studies discuss the state-of-the-art hydrogen technologies and purpose in the emission-free energy system. Yue et al. [31] concluded that hydrogen systems are not cost-optimal compared to today's alternative systems. Staffel et al. [32] showed a huge collection of hydrogen technologies for all relevant sectors including industry, residential and transport and discussed mitigation options by using hydrogen. Another study by Brandon et al. [33] in 2017 discussed the use of hydrogen in energy systems in different sectors. Quarten et al. [34] also considered hydrogen in the energy system. They came to the result that temporal resolution has an impact on the demand of hydrogen, and thus hydrogen demand could be underestimated in today's models. Dodds et al. [35] have more focus on the heating sector as they investigated fuel cells for residential demand. This study discussed the technology's readiness and concluded that most results of energy system models do not show hydrogen in residential applications, which veils the usability of hydrogen for decision-makers. In the industrial sector, in accordance to IRENA [36], hydrogen will be important for chemical industry, steel, international shipping, aviation and high temperature heat generation.

Germany's energy system was covered in several investigations known as "big 5" [37–41] towards the transformation to net zero until 2045. In a study by BCG [38], hydrogen and synfuels are used in transport, industry and the residential sector. A total demand of 240 TWh is reported, while 130 TWh need to be imported. In a study by dena [37], a final energy demand of 226 TWh of hydrogen can be found, while 597 TWh need to be imported overall. In a study [39] by the Ariadne project, the results show that hydrogen can play a major role. Germany records a hydrogen demand of 40 TWh by 2030. To satisfy the total energy demand, imports are necessary. The report shows up to 1500 TWh/a and up to 900 TWh/a of foreign electricity production to satisfy the synfuel and hydrogen demand. In Sensfuss et al. [40], either an import of 510 TWh of hydrogen or 750 TWh of synfuels is necessary to decarbonize Germany's energy system. Finally, in a study by Öko-Institut et al. [41], 36% of the 265 TWh demanded hydrogen is supplied by domestic production. All five studies rely on hydrogen and synfuel imports, while the demand for direct electric use in the final energy consumption is also rising tremendously.

The literature review shows that there has been intensive scientific study of the production and distribution of hydrogen or synfuels. However, little attention has been paid to the global allocation. A study with a global view taking hydrogen and synfuels into account in terms of import and export under consideration of the 1.5 °C target and the security of supply policies of world regions is not discussed so far.

3. Methodology

To analyze the role of hydrogen and synfuel usage and trades across regions, the global energy system model TIAM is used (see Section 3.1). To handle the technical and economical availability of synfuels and hydrogen, the model is extended. In Section 3.2, the implementation of the cost potential curves is discussed and shown on the example of hydrogen. Sections 3.3 and 3.4 show details on the calculation of the hydrogen and synfuel cost potential curves, as well as the underlying potentials for renewable energies. Lastly, in Section 3.5 the sectors of TIAM and the implementations of end use demand technologies for hydrogen and synfuels are covered.

3.1. Global Energy System Model TIAM

Energy system models are used to measure the impact of climate policy and find path dependencies when decarbonizing the energy system.

In this study, the global energy system TIAM [42] is used. TIAM is a technology-rich bottom-up optimization model minimizing the total discounted system costs. On a spatial level, TIAM considers 16 regions, in which some regions are their own countries (e.g., the US) and others are aggregated (e.g., Africa); see Figure 1. Table A3 provides further information about the TIAM regions.

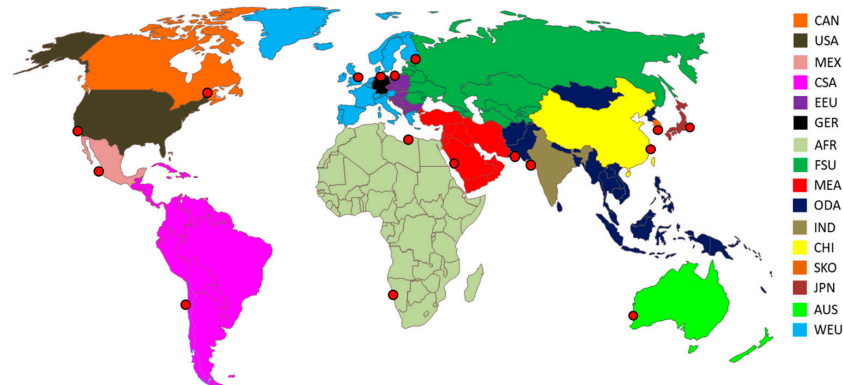


Figure 1. TIAM map with selected harbors (red dots) for each region.

As a starting point of the underlying methodology, commodities are provided by domestic mining or imports as primary energy for further processing. Certain parameters are exogenously set as energy prices or potentials for mining. The primary energy is provided to be converted to the final energy sectors to satisfy the end use demand.

The end use sectors in TIAM are split into five different sectors (industry, transport, households, commercial and agriculture) (see Figure 2). TIAM distinguishes between processes and commodities. Processes are meant as all technologies that produce or provide commodities, e.g., cars in the transport sector or heating technologies in the household sector. All technologies have certain properties, such as their lifetime, investment costs, operation and maintenance costs and availability. The whole procedure is based on investment decisions. These properties ensure that there is a competition of all the technologies and a cost-optimal path can be found. Commodities are defined as all energy carriers (e.g., coal, oil, hydrogen, etc.) or materials (e.g., steel, cement, etc.) and can be produced out of technology processes, as well as emissions.

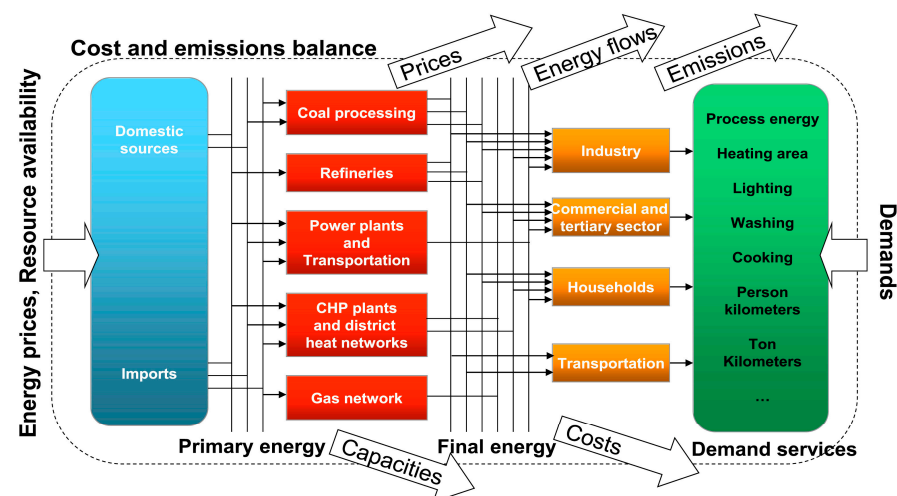


Figure 2. Energy system model TIAM scheme. Source: [43].

The time horizon TIAM considers starts in 2015 and ends in 2100. The demand is based on the statistics of the base year in 2015, and it is projected via drivers such as GDP or changes in population. Furthermore, TIAM distinguishes between twelve time slices. There are four for each season and three for day, night and the peak hour.

3.2. Modeling of the Supply Curves in TIAM

Energy system models can only make limited statements with regard to high geographic resolution. To implement hydrogen and synfuels geographically well in TIAM, the approach of discrete cost supply curves was chosen. Therefore, different steps were derived based on GIS data, as explained in the next section. The specific implementation of the supply curves in TIAM is shown in Figure 3. H2SupplyLOC and H2SupplyEXP represent the cost curves for both local and export hydrogen with full costs (full production of hydrogen, storage and transport). Inputs and outputs of the hydrogen production are both integrated in TIAM, in order to evaluate the expansion of renewable energies, too. Furthermore, capacities are represented to ensure that the overall technical potentials of renewable energies are not exceeded and that the competition of all sectors using the mentioned capacities is given. The techno-economic data for hydrogen and synfuel production is provided in Table 1. Hydrogen and synfuels can then be used for local or export demands. Shipping technologies are provided for overseas transport; compare Table A1. Local distribution technologies are implemented to map the transport and distribution costs of hydrogen and synfuels within one region.

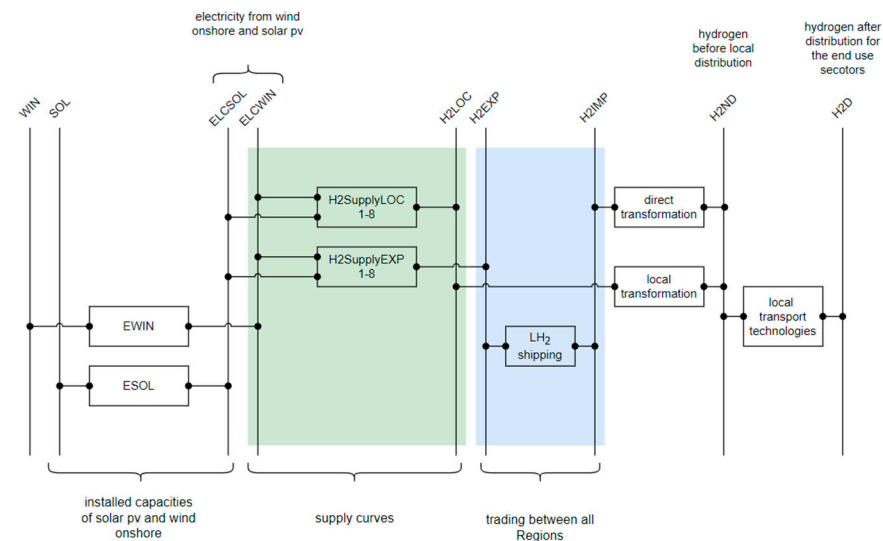


Figure 3. Implementation of aggregated cost supply curves shown on the example of hydrogen.

3.3. Supply Curve Hydrogen

Based on the methodology and results described in Franzmann et al. [44] for each of the 16 world regions in TIAM, at least one country with beneficial renewable wind or solar conditions was selected to serve as the green hydrogen hub of the respective region. The regionally and spatially resolved renewable energy potentials serve as the input for the electrolysis for hydrogen production, as well as an input for the liquefaction of hydrogen in the export harbor. The water supply for the electrolysis is considered as an additional cost factor. Competing demand for the renewable electricity is not considered in the export cost potentials of liquid hydrogen. Hence, at this step, the full renewable energy potentials of wind turbines and open-field photovoltaic are assumed to be available for hydrogen production and liquefaction. The hydrogen export energy system is holistically optimized within FINE [45] using the optimal combination of curtailment, storages, wind and PV combination and grid expansions. In a postprocessing step, the local grid connection costs

are considered by modelling the electric grid connections of the location-specific turbines and PV parks from the optimization via a minimum spanning tree approach.

Table 1. Techno-economic assumptions for wind onshore, solar PV and biomass in TIAM. Source: [46–48].

	CAPEX [EUR/KW]				OPEX [% of CAPEX]	Lifetime [y]
	2020	2030	2040	2050		
wind onshore	1.257	1.137	987	923	3.0%	25
solar PV	703	395	340	326	1.0%	25
biomass	2.000	2.000	2.000	2.000	2.0%	40
electrolyser	900	700	575	450	1.5%	19

To implement the detailed cost potential curves into TIAM (see Figure 3), each step is used as a separate technology in TIAM representing a specific amount of the liquid green hydrogen at the harbor and its respective costs. In this study, we have chosen 8 evenly-spaced hydrogen costs steps to maintain a sufficient level of detail, while avoiding too big an increase in calculation time for TIAM as each step increases the model size. This aggregation is repeated for different years starting from 2020 until 2050, in 10 year steps. For the range of 2050–2100, the values of 2050 are used. The obtained cost for each liquid hydrogen potential part contains the whole system cost across the full process chain from renewable energy technologies to the ready to export liquid hydrogen in the harbor.

A brief overview of the total liquid green hydrogen export potentials is given in Table 2. As expected, the results indicate that the size of the region and the size of the hydrogen potential depend on one another. Regarding the export cost, a clear pattern with a lower hydrogen cost in regions with beneficial solar conditions can be identified as already discussed in Franzmann et al. [44].

Table 2. Liquid green hydrogen export potentials and costs per region in 2050 [44].

	AFR	AUS	CAN	CHI	CSA	GER	EEU	FSU	IND	JPN	SKO	MEA	MEX	ODA	USA	WEU
Potential [TWh]	188	433	76.9	155	154	0.5	1.1	104	21.8	0.7	0.1	196	53.6	24.5	128	3.8
Minimal Costs [EUR/MWh]	58.5	71.6	117	99.4	62.4	94	93	76.2	70.8	89	85	53.9	103	63.8	79.4	84.7

3.4. Supply Curve Synthetic Fuels

It is assumed that all available renewable energies are not competing and available just for synfuel production. In other words, the local and competing demand of renewable energy is neglected.

The synthetic fuels' potentials and costs are determined by aggregating a decentralized cost-minimal energy system based on the open-source tool *urbs* [49]. The production of synfuels is basically a hydrogen production with intermediate storage and a subsequent Fischer–Tropsch process. The needed carbon for the Fischer–Tropsch process stems from either biomass or the atmosphere by the DAC process. The water supply for the electrolysis is described by a fixed-cost factor equal to the one for the hydrogen supply. The transport costs are estimated by the distance to the nearest maritime port; all ports can be found in Table A2.

Table 3 shows the exemplary results of the analysis for the year 2050. The potentials as well as the costs follow the regions with high solar potential, because of its low levelized cost of electricity (Buchenberg et al. [50]).

Table 3. Synfuels' export potentials and costs per TIAM regions in 2050 [50].

	AFR	AUS	CAN	CHI	CSA	GER	EEU	FSU	IND	JPN	SKO	MEA	MEX	ODA	USA	WEU
Potential [TWh]	139,463	321,855	54,953	113,924	113,060	436	873	83,303	16,120	482	112	145,219	39,621	18,158	95,650	2839
Minimal Costs [EUR/MWh]	80.3	81.6	117.9	82.4	80.8	97.8	94.1	100.9	88.8	108.9	94.6	81.1	85.0	79.9	90.3	85.0

3.5. Sector Modeling

In the power sector, hydrogen can be used as fuel input for combined cycle turbines [51]. The capex is slightly higher compared to gas turbines, but it can also contribute to peak load. Furthermore, hydrogen combined heat and power (CHP) plants are included that can take the power output for the power sector [52].

In the residential and commercial sector, hydrogen burners for room heating are modelled and included. The outgoing heat from CHP processes can also be used via the district heating network for households [53,54].

The transport sector provides mostly fossil-fueled technologies based on the 2015 starting year of the model. The technologies that use diesel can switch to synthetic diesel without reinvesting. The same works for all existing aviation technologies based on fossil jet fuel. Technologies for future investment also have the possibility to switch between fossil and synthetic fuel during their whole lifetime. In addition to the fuel switching option of fossil-fueled technologies, hydrogen-based technologies are also taken into consideration, especially for heavy load trucks, buses, shipping and aviation (cf. [55–57]).

In industry, hydrogen can be used for direct reduced iron (DRI). It can also be used as feedstock for ammonia production via a Haber–Bosch process, as well as a feedstock for methanol production. As well as the non-energy use of hydrogen, it can also be used for processing heat and steam [36].

4. Results

4.1. Scenario Definitions

To evaluate the transformation of the global energy system, four scenarios are compared (see Table 4). In the BAU scenario, no climate policy is implemented. This is used as a reference scenario to evaluate the transformation. In the 1_5D scenario, a climate budget is specified according to IPCC, which may be consumed over the model horizon of 2015–2100. In this scenario, there are no trade restrictions or minimum production levels of hydrogen and synfuels. In order to study energy security and transformation impacts, the SoS1 scenario assumes 50% domestic production of hydrogen and synfuels, with no minimum number of trading partners. In scenario SoS2, a minimum local production of 33% per region is provided. In order to ensure energy security despite reduced own production, trade is only possible with at least two independent regions, where none of the trading regions may cover more than 33% of the total demand.

Table 4. Scenario description.

No.	Scenario Name	Description
1	BAU	No climate policy.
2	1_5D	1.5 °C conform scenario based on given CO ₂ budget for 2015–2100 (cf. [2]).
3	SoS1	Security of Supply scenario, based on 1_5D scenario. Further implementation: at least 50% of hydrogen and synfuels must be out of domestic production. No restriction for trading.
4	SoS2	Security of Supply scenario, based on 1_5D scenario. Further implementation: at least 33% of hydrogen and synfuels must be out of domestic production. At least two trading partners. Each trading partner can satisfy a maximum share of 33% of the local demand.

4.2. CO₂ Reduction Measures

In order to achieve the 1.5 °C target, the global net emissions need to decline drastically. Starting in 2015, over 30 Gt of CO₂ net emissions were emitted (cf. [3]). This is due to the reason of massive shares of fossil fuels in both electricity generation and final energy consumption in 2015. In order to keep the carbon budget for the 1.5 °C target, a massive transformation to net zero is necessary (see Figure 4). This is firstly done by phasing out coal in 2030, which already has a massive effect in CO₂ mitigation and leads to a reduction of over 10 Gt of CO₂. In 2040, the possible use of CCS leads to a shift towards biomass CCS (BECCS) as well as gas CCS in the climate mitigation scenarios (1_5D, SoS1 and SoS2). This makes net zero possible in 2050, whereas CO₂ emissions of the BAU scenario show only a little difference.

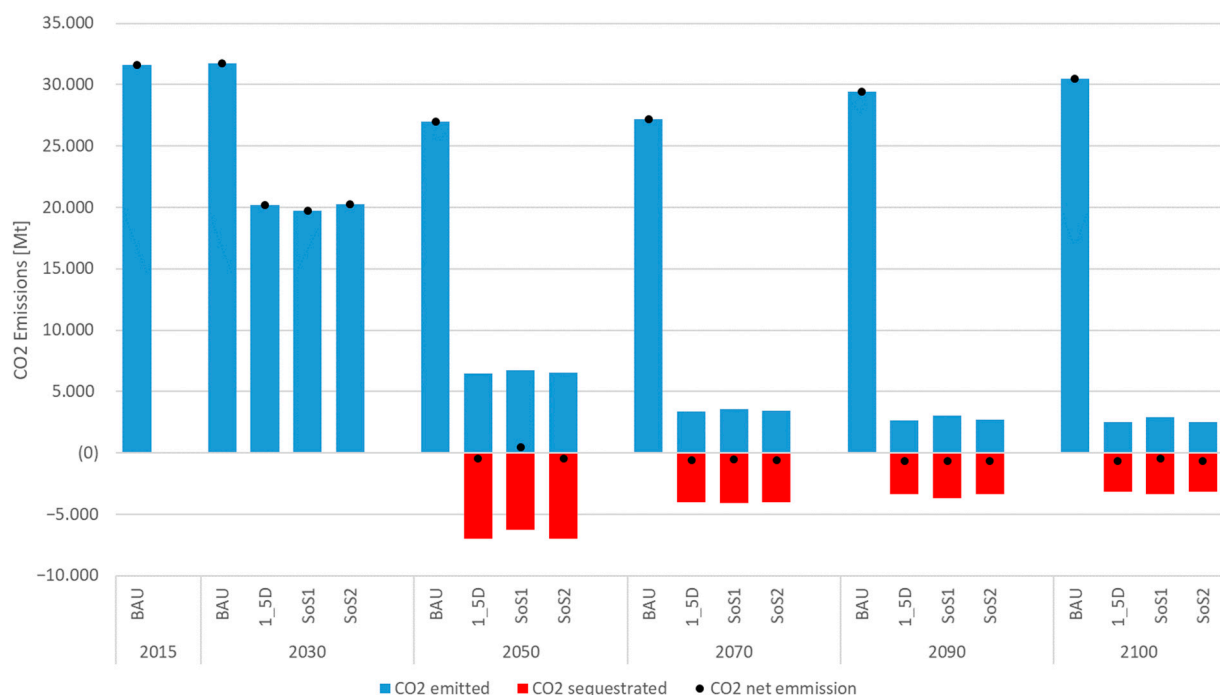


Figure 4. Global CO₂ emissions across all scenarios.

The share of CCS in 2050 is quite high, as over five Gt of CO₂ must be sequestered, because of emissions which cannot be set to zero, such as those in the agriculture sector. Even in transport and industry, the shift in technologies is slow as some technologies, especially in the industry, have lifetimes of more than 30 years. Therefore, BECCS is used to have negative emissions in order to achieve net zero in 2050; see Figure 5.

As the expansion of renewable energies as well as the transformation in the end use sectors is ongoing, the amount of CO₂ is declining over the years for the scenarios with climate policy. The differences in these scenarios are not huge, because the transformation pathway within the regions is almost identical even if there are security of supply scenarios applied to the production and trading of hydrogen and synfuels. No application of climate policies leads to remaining emissions of roughly 30 Gt in 2100, as coal and gas are still used in the final energy consumption as well as in electricity generation.

The electricity generation mix based on [4] is recorded as 24,292 TWh (cf. Figure 5). With over 40% of coal and 21% of natural gas share in 2015, the global electricity generation needs a huge transformation towards renewable energies to decarbonize the sector. In addition to the fact that the electricity generation is mostly fossil-based in 2015, even more electricity is needed to decarbonize the other sectors as well as dealing with economic growth, which will also lead to a rising demand in energy.

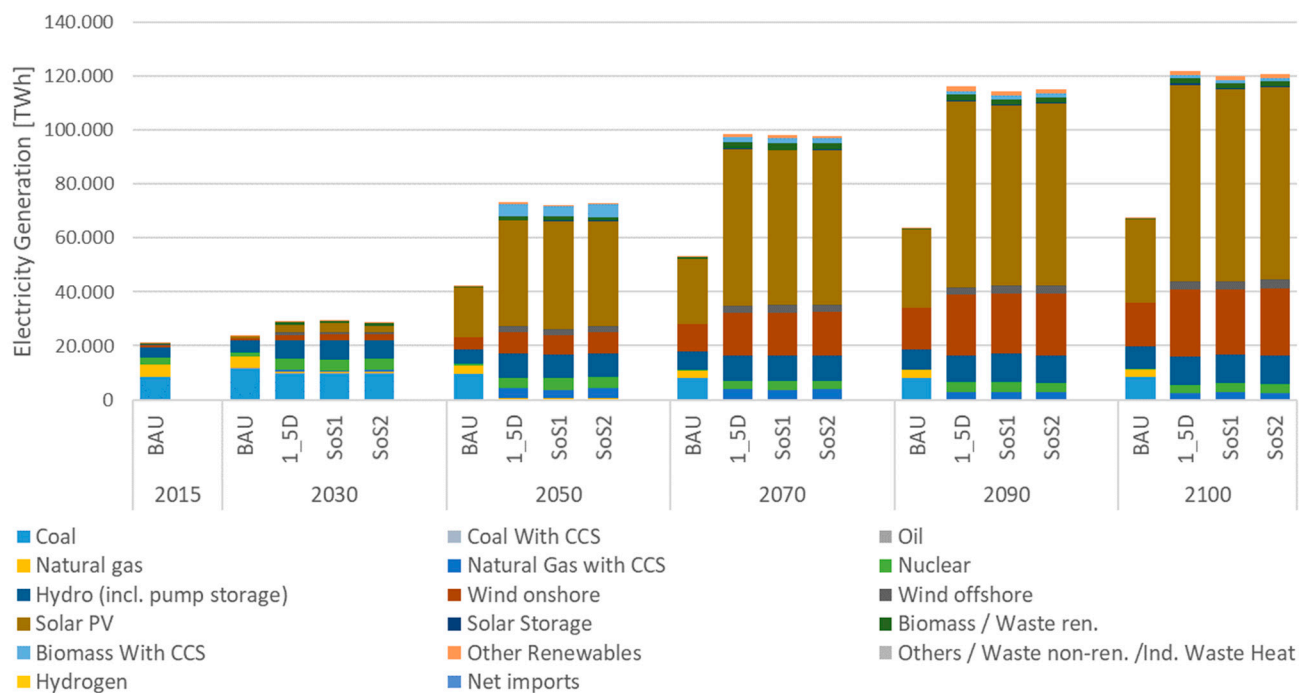


Figure 5. Global electricity generation.

In 2030, the transformation process can be seen already. While in the BAU scenario the rising total demand is satisfied by adding more fossil fuels, the scenarios with climate policies (1_5D, SoS1 and SoS2) show more generation by renewable energies. The amount of hydropower is expanded to its maximum, while gas and coal are both decreasing. The scenarios with climate policies applied show 24% more electricity generation compared to BAU.

In 2050, most of the electricity sector is already fossil-free in the climate policy scenarios. Coal as an energy carrier is almost faded out, with only 108, 62 and 102 TWh remaining for 1_5D, SoS1 and SoS2, respectively. However, the biggest difference can be seen in the amount of generation by PV and wind onshore. In comparison, 75% more electricity generation is needed for climate action, compared to BAU.

This trend is continued until 2100. In 2070, the electricity sector becomes fully carbon neutral while gas and biomass plants with CCS are applied to satisfy the peak residual load demand. The demand for hydrogen and synfuels can also be seen in Figure 5, as hydrogen needs roughly $1.7\times$ and synfuels $2.1\times$ – $2.5\times$ of their energy content as input, while the overall electricity demand is rising, too. This leads to a total demand of 120,000 TWh in 2100 in order to achieve the 1.5 °C target. Compared to this, in the case of no climate protection the total amount of electricity still rises to 67,000 TWh. Overall, the electricity demand rises to $6\times$ the amount in 2015 considering climate action and additionally does more than triple in the case of BAU. Even though there is no climate policy implemented in BAU, a transformation towards renewable energies can also be seen, while peak load demand is satisfied with gas and coal plants.

The comparison of 1_5D, SoS1 and SoS2 shows that through all those years the electricity generation profiles do not show huge differences. This means that the feasible renewable potentials are high enough for each region to achieve the 1.5 °C target, and trading regions can be substituted (compare SoS1 and SoS2) without an appreciable increase of the production intensity of hydrogen or synfuels.

4.3. Final Energy Demand

The global final energy demand was close to 96,000 TWh in 2015. Coal, gas and petroleum products have a total share of over 50% (see Figure 6). In 2030, the amount of

electricity in the final energy consumption mix is rising. In all sectors, electric technologies mostly have efficiency advantages. The first steps towards a renewable energy system can be seen. In the BAU scenario, the amount of coal is rising, whereas in 1_5D, SoS1 and SoS2 coal phase-out is already starting. Compared to 2015, the remaining share of coal is only 10% for all scenarios with the 1.5 °C target.

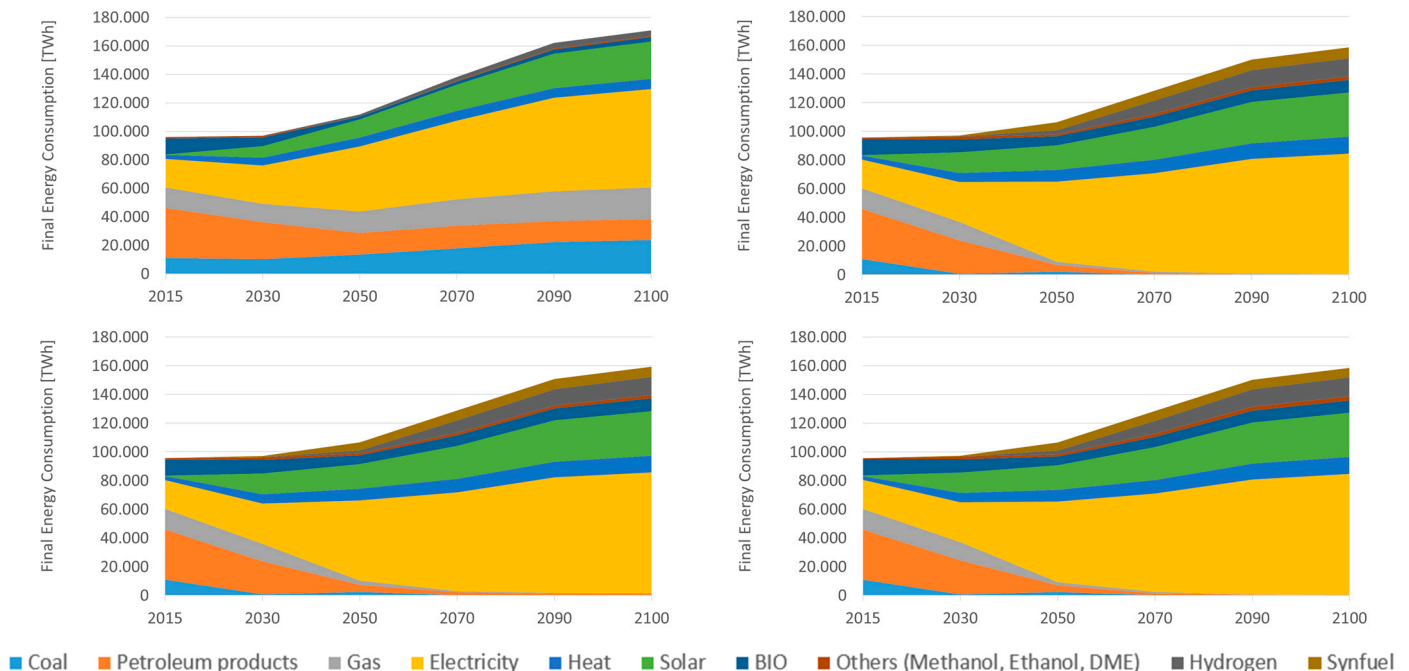


Figure 6. Global final energy consumption along all scenarios. BAU is top left, 1_5D is top right, SoS1 is bottom left and SoS2 is bottom right.

In 2050, most of the energy system, considering climate action, is decarbonized. The residential and commercial sector both switch fuel for heat demand mostly to electricity by using heat pumps for all regions with a cold winter. District heating also plays its role. All regions with a higher average temperature also have a rise in electricity demand for room cooling. The transport sector is transforming towards direct electric usage. Passenger cars use electricity as input, while domestic and international aviation and shipping move to a split share of hydrogen and synfuels. In the 1_5D scenario, the hydrogen demand is 2776 TWh; for SoS1 it is 2055 TWh and for SoS2 it accounts for 2688 TWh. The synfuel demand is 5761 TWh, 5745 TWh and 5572 TWh. There are two reasons for this effect. First, the security of supply policies of domestic production in SoS1 (minimum of 50%) and SoS2 (minimum of 33%) lead to exceeding the feasible technical potentials of renewable energies for some regions, so direct electric use is favored. Secondly, in SoS2, demand must be fulfilled by at least two different export regions, if it is not possible to produce 100% domestically. This exogenously required flexibility leads to more total usage of hydrogen and synfuels in SoS2 in 2050. As SoS1 has the lowest absolute demand in hydrogen and synfuels in 2050, the demand for electricity is therefore higher. Without climate policies, the demand in coal is rising; see BAU. Nevertheless, the share of electricity is also rising, which shows that direct electric technologies are also economically without CO₂ pricing.

Towards 2100, the energy system is fully decarbonized in the climate policy scenarios, mostly fueled by electricity, whereas BAU still has an over 30% share in fossil fuels. The effect of 2050 with the climate action scenarios can also be seen in 2100. With a total demand of 20,182 TWh of synfuels and hydrogen, the 1_5D scenario has the highest demand compared to SoS1 with 19,559 TWh and SoS2 with 19,615 TWh. Even if the results do not differ much, it can be seen that there is at least a minimal impact on the demand considering security of supply policies on production and trading.

As both international and domestic aviation and shipping as well as some processes in the industrial sector cannot switch towards direct electric use, hydrogen and synfuels are necessary to fully decarbonize the energy system, which is only applied by climate policy.

4.4. Global Hydrogen and Synfuel Production

One of the key questions of transforming the energy system towards carbon neutrality is the allocation structure of the hydrogen production. As some regions are limited in adding additional capacities for PV and wind onshore, this could be the limiting factor when trying to keep the carbon budget until 2100. Considering the BAU scenario, the results show that hydrogen is used in the final energy consumption, as seen in Figure 6, and therefore is locally produced. There is no export of hydrogen in 2100, while synfuels are neither produced nor exported; see Figures 7–9. The detail value information is found in Table A4.

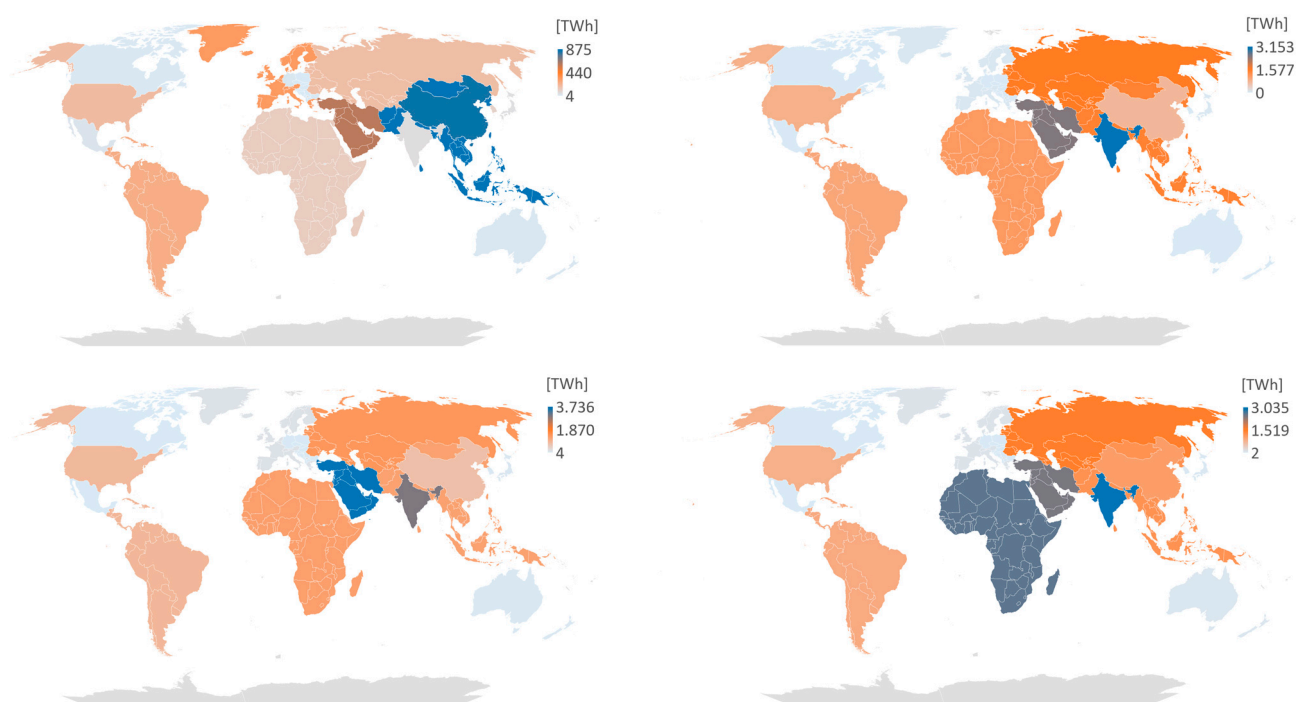


Figure 7. Hydrogen production along all scenarios in 2100. BAU is top left, 1_5D is top right, SoS1 is bottom left and SoS2 is bottom right.

The structure of production is starting to change as more and more renewable energy capacities are required to satisfy the overall electricity demand; compare Figure 5. Without security of supply applied to trading and production, India has the highest amount of domestic production in the 1_5D scenario with 3153 TWh; see Figure 6. Furthermore, there are certain regions where hydrogen is not produced at all, especially in the whole of Europe and Canada. By applying security of supply to have a minimum production of 50% in each region, there is already a shift visible. While the overall synfuels and hydrogen amount is shrinking in SoS1 compared to 1_5D, it can be seen that hydrogen production is boosting in comparison to synfuels; compare Figures 7 and 9. As a minimum of 50% of domestic production for synfuels and hydrogen is mandatory, the shift is going onwards to hydrogen production; see SoS1 in Figure 7. This is due to the reason that hydrogen production is less energy-intensive, and some regions have fewer potentials for PV and wind onshore to produce hydrogen and synfuels. It also depends on the overall structure. Given the case of India, without security of supply in the 1_5D case, the hydrogen production is the highest of all regions while there is no production of synfuels at all (see Figure 9). Synfuels are 100% imported in that case. By adding security of supply with a minimum of

50% domestic production, India is shrinking its hydrogen production while boosting the synfuels production. The residual demand is satisfied by imports of other regions.

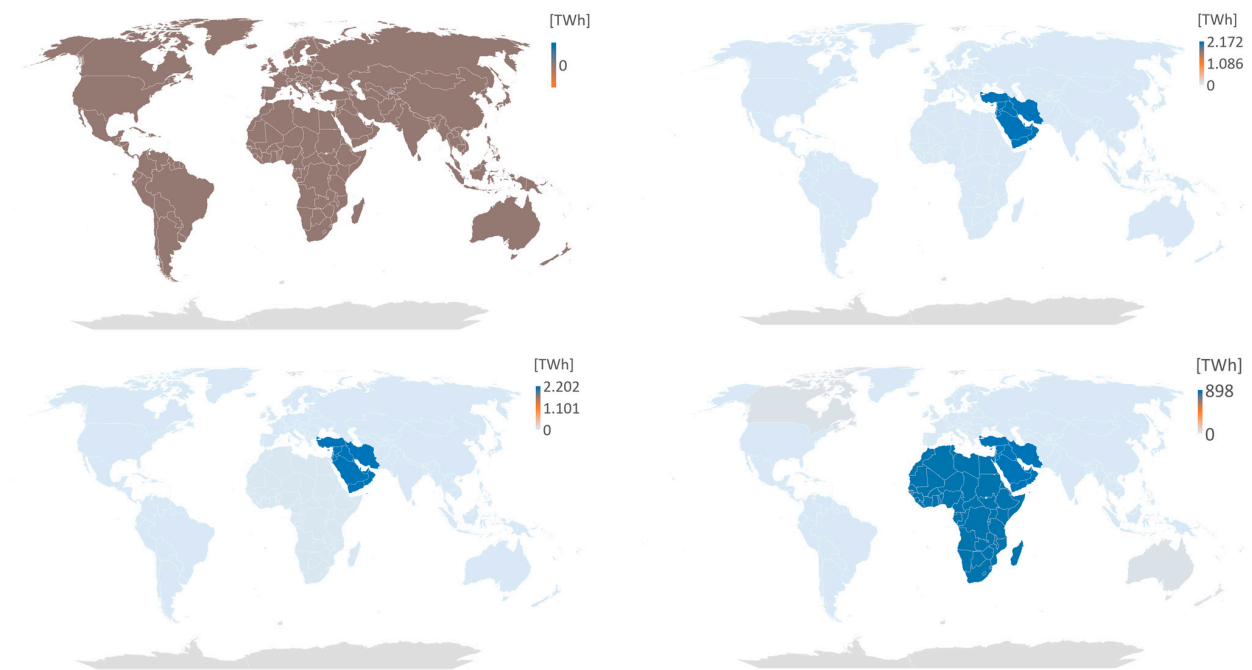


Figure 8. Hydrogen Export along all scenarios in 2100. BAU is top left, 1_5D is top right, SoS1 is bottom left and SoS2 is bottom right.

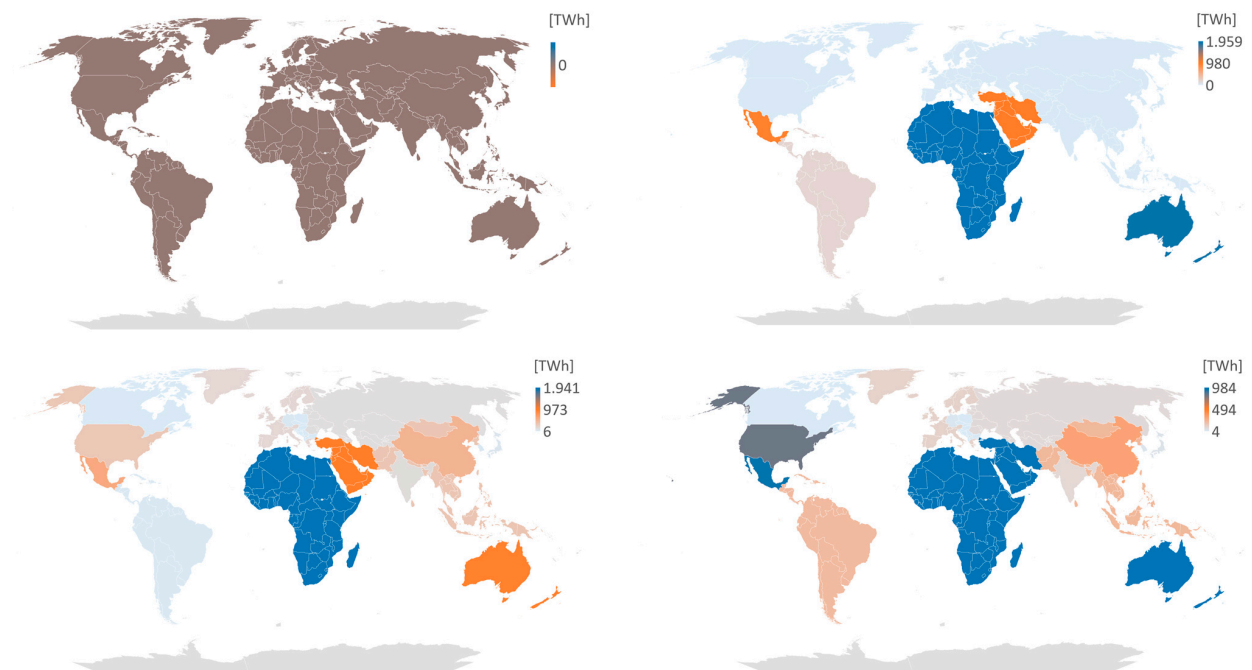


Figure 9. Synfuel production along all scenarios in 2100. BAU is top left, 1_5D is top right, SoS1 is bottom left and SoS2 is bottom right.

Given the case of a minimum of 33% in domestic production and at least two independent trading regions, there is another shift in hydrogen and synfuels allocation visible. Middle East Asia and Africa are starting to boost the hydrogen production in SoS2 as they become the main global exporters; compare Figure 8. As the domestic production share of synfuels and hydrogen on the total demand is less than in SoS1, many regions can use the

feasible renewable potentials to produce more local hydrogen as synfuels can be imported to a maximum share of 66%.

The export allocation structure for hydrogen in Figure 8 shows clearly that Middle East Asia has the lowest levelized costs on hydrogen production globally. Furthermore, the location is predestined for LH₂ transport to Europe as the distance is relatively short, and transport costs have a huge impact on the total costs of hydrogen. As far as there is no security of supply scenario applied to trading (1_5D and SoS1), Middle East Asia remains the main global exporter of hydrogen.

By adding security of supply to trading in the case of SoS2, Middle East Asia is no longer allowed to satisfy the export demand as one region. This results in Africa and Middle East Asia sharing the export demand, as they both have huge technical potentials as well as being a short distance to Europe, which is the main importer.

In 1_5D, it can be seen that the import demand for synfuels is highest; compare Figure 10. Middle East Asia, Africa and Australia are the main exporters and share more or less the same amount of synfuel exports. Mexico also exports some synfuels, especially to Canada and the US.

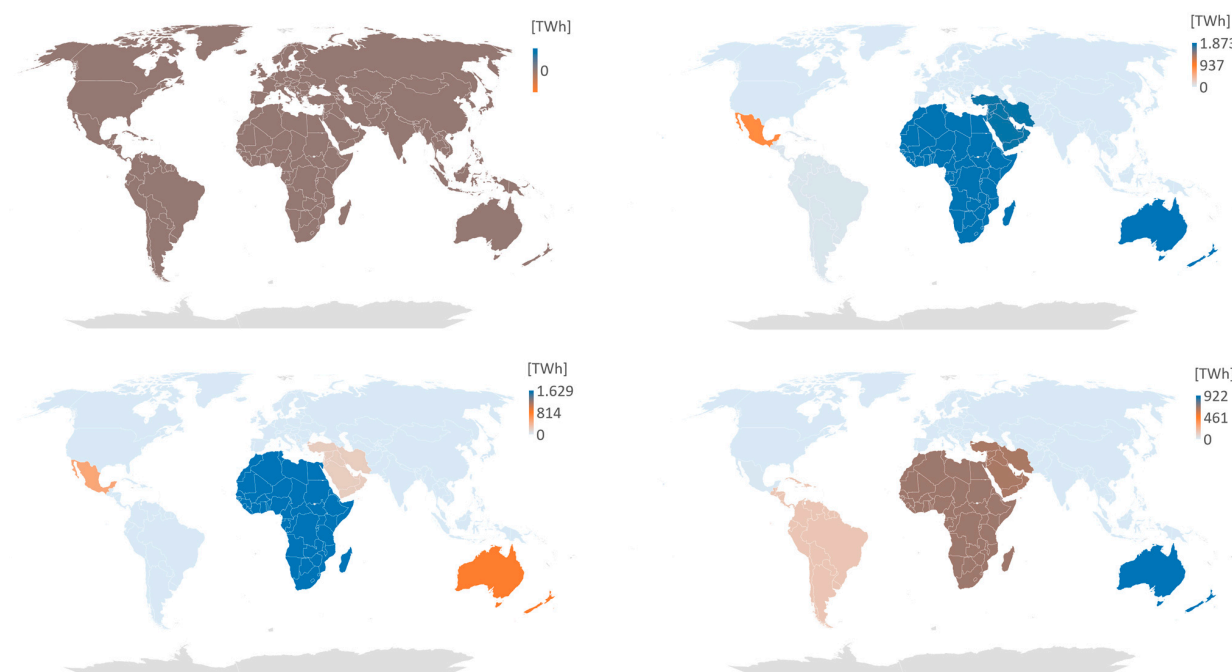


Figure 10. Synfuel export along all scenarios in 2100. BAU is top left, 1_5D is top right, SoS1 is bottom left and SoS2 is bottom right.

Considering the SoS1 scenario, the demand of synfuels export is shrinking, especially in the regions of Middle East Asia and Australia, while the regional allocation structure is still the same. The lowest export demand is observed in the case of SoS2. A switch in export allocation can be seen as Mexico is replaced by Central and South America. Australia, Middle East Asia and Africa still remain the main exporter of synfuels.

5. Conclusions and Outlook

The scenario analysis with the energy system TIAM shows that CO₂ mitigation due to technological transformation, electrification and a new allocation of energy carriers, especially hydrogen and synfuels, is necessary.

To achieve the 1.5 °C target, the transformation of the power sector is crucial. On the one hand, a large share of the final energy consumption is covered by direct electric use. On the other hand, it must be ensured that hydrogen and synfuels can be produced despite the high use of electricity to replace those technologies that cannot switch to direct

electric, such as aviation, shipping and some high temperature process heat processes in the industrial sector.

The scenario analysis also shows, independently of the import structure and requirements related to security of supply or the diversity of energy imports, that the electricity sector and the end use sectors decarbonize in a fairly similar way. Electricity is the preferred energy source. The share of hydrogen and synfuels depends on the difference in the security of supply policies exogenously applied to the scenarios, but both play an important role in global markets.

In the only scenario with climate action and no security of supply policy, it shows that not all regions start the production of hydrogen and synfuels, because the renewable energy potentials for this are not sufficient and competitive compared to direct electricity usage. This is particularly evident in Europe. Preference in those regions is given to importing hydrogen from Middle East Asia. Synfuels show a higher degree of diversification and therefore a different allocation in terms of export. Africa, Middle East Asia and Australia have similar export shares.

To conclude this investigation, it can be said that the technical renewable potentials are high enough to decarbonize the global energy system. The structure of hydrogen and synfuel allocation is fairly different in the case of security of supply policies on production and trading. Shifts can be observed as sun-rich regions are more predestined to produce hydrogen and synfuels. Furthermore, the transformation process will not only be influenced by the availability of renewable electricity generation, but also by the infrastructure costs, which are included in the supply curves that TIAM is using as an input. This does also have an impact on the energy carrier allocation regarding the final energy consumption, but it does not necessarily threaten the 1.5 °C target.

The energy system model TIAM has a high degree of technology richness. Nevertheless, mitigation strategies are required as material efficiency and circular economy will have a huge impact on the overall energy supply as well as on the hydrogen and synfuel demand. By using secondary routes for material production, direct electric usage could become the leader in certain sectors, e.g., the steel or chemical industries. There are also uncertainties in supply technologies that could lead to a shift towards direct electric use, for example, molten oxide electrolysis for primary steel production. A diffusion with such a technology could potentially set hydrogen demand in primary steel production to almost zero. This example shows the uncertainty related with future hydrogen demands.

It is also unclear how states will behave on boosting the hydrogen economy. As the results show, little changes already have impact on the allocation structure. Moreover, the model results fully rely on levelized costs of hydrogen and synfuels. Tax subsidies such as those in the IRA could lead to a shift in hydrogen production, expansion of renewable energies and therefore, a total new global allocation of energy carriers.

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Appendix A

Table A1. Distance matrix for shipping based on [58].

km	CAN	USA	MEX	CSA	EEU	GER	AFR	FSU	MEA	ODA	IND	CHI	SKO	JPN	AUS	WEU
CAN		13,187	4820	17,600	7327	6493	9587	8313	13,836	15,420	16,407	22,781	21,292	18,851	23,658	5820
USA	13,187		7200	16,051	16,337	16,727	16,776	19,076	22,646	21,843	20,577	10,648	9834	9182	18,534	17,852
MEX	4820	7200		13,296	14,546	11,147	14,904	12,464	15,554	24,272	18,997	13,105	12,323	11,521	22,000	12,284
CSA	17,600	16,051	13,296		13,865	12,562	13,546	14,691	21,161	24,261	19,466	23,022	23,853	24,264	21,366	14,433
EEU	7327	16,337	14,546	13,865		819	6986	1191	9167	16,044	12,836	21,483	22,348	22,232	20,772	1393
GER	6493	16,727	11,147	12,562	819		6722	1637	8130	12,834	12,329	20,235	21,591	21,484	21,156	917
AFR	9587	16,776	14,904	13,546	6986	6722		11,349	4257	8847	11,755	25,177	26,677	16,500	16,686	6412
FSU	8313	19,076	12,464	14,691	1191	1637	11,349		9852	17,188	13,854	21,903	22,888	23,430	22,641	2461
MEA	13,836	22,646	15,554	21,161	9167	8130	4257	9852		4758	4254	12,530	13,119	13,497	12,895	7745
ODA	15,420	21,843	24,272	24,261	16,044	12,834	8847	17,188	4758		513	10,249	10,802	12,436	9598	11,804
IND	16,407	20,577	18,997	19,466	12,836	12,329	11,755	13,854	4254	513		9539	10,308	11,100	9342	11,917
CHI	22,781	10,648	13,105	23,022	21,483	20,235	25,177	21,903	12,530	10,249	9539		838	1850	8048	19,939
SKO	21,292	9834	12,323	23,853	22,348	21,591	26,677	22,888	13,119	10,802	10,308	838		1662	8792	25,557
JPN	18,851	9182	11,521	24,264	22,232	21,484	16,500	23,430	13,497	12,436	11,100	1850	1662		9542	23,037
AUS	23,658	18,534	22,000	21,366	20,772	21,156	16,686	22,641	12,895	9598	9342	8048	8792	9542		20,010
WEU	5820	17,852	12,284	14,433	1393	917	6412	2461	7745	11,804	11,917	19,939	25,557	23,037	20,010	

Appendix B

Table A2. Ports in TIAM for hydrogen and synfuel import and export. This is our own research.

Region	Port Name	Lat	Lon
AFR	Port of Walvis Bay	−2,294,438,616	1,448,237,595
SKO	Port of Busan	3,510,370,188	1,290,414,886
CSA	Port of Buenos Aires	−3,456,909,495	−5,838,273,273
AUS	Fremantle Ports	−320,529,628	1,157,408,536
CAN	Port of Quebec	4,682,265,707	−7,120,249,041
CHI	Port of Shanghai	3,063,068,515	1220,847,303
GER	Port of Hamburg	535,410,807	9,986,766,343
WEU	Port of Birmingham	5,363,207,459	−185,406,508
IND	Mundra Port	2,274,104,731	697,157,146
JPN	Port of Keihin	3,542,669,641	1,396,843,441
AFR	Port of Benghazi	3,211,470,309	200,423,606
MEX	Puerto De Manzanillo	197,070,599	−71,744,7426
ODA	Port of Karachi	2,483,708,206	6,698,086,793
EEU	Port of Gdynia	545,360,318	1,853,554,754
FSU	Port of Saint Petersburg	5,988,860,049	3,018,117,919
MEA	Port of Jeddah	2,149,503,622	391,551,345
USA	Port of Los Angeles	3,372,839,414	−1,182,402,335

Appendix C

Table A3. Description of TIAM regions; compare [59].

TIAM Region	Region Name	Further Description
AFR	Africa	Full African continent
AUS	Australia	Australia, New Zealand
CAN	Canada	-
CHI	China	-
CSA	Central and South America	Full South America and North America except Canada, USA and Mexico
EEU	Eastern European Union	Albania, Bosnia–Herzegovina, Bulgaria, Croatia, Czech Republic, Hungary, Macedonia, Poland, Romania, Slovakia, Slovenia, Yugoslavia
FSU	Former Soviet Union	Russia and old Soviet states
GER	Germany	-
IND	India	-
JPN	Japan	-
MEX	Mexico	-
MEA	Middle East Asia	Near East except Africa
ODA	Other Developing Asia	Asia except China, India, Japan and South Korea
SKO	South Korea	-
USA	United States of America	-
WEU	Western European Union	Portugal, Spain, France, Great Britain, Sweden, Norway, Finland, Italy, Greece, Switzerland, Austria

Appendix D

Table A4. Production and export amounts of hydrogen and synfuels. All values in TWh.

	Hydrogen Production				Hydrogen Export				Synfuel Production				Synfuel Export			
	BAU	1_5D	SoS1	SoS2	BAU	1_5D	SoS1	SoS2	BAU	1_5D	SoS1	SoS2	BAU	1_5D	SoS1	SoS2
AFR	125	1154	1276	2593	0	13	18	866	0	1959	1941	984	0	1835	1629	672
AUS	15	13	39	59	0	0	0	32	0	1873	939	984	0	1873	852	922
CAN	11	2	4	2	0	0	0	0	0	0	8	5	0	0	0	0
CHI	826	734	734	1050	0	0	0	0	0	0	487	318	0	0	0	92
CSA	247	972	871	894	0	0	0	0	0	184	21	217	0	41	0	152
EEU	4	8	10	6	0	0	0	0	0	0	6	4	0	0	0	0
FSU	180	1577	1416	1477	0	0	0	0	0	0	121	75	0	0	0	0
GER	18	0	8	5	0	0	0	0	0	0	30	20	0	0	0	0
IND	59	3153	2962	3035	0	0	0	0	0	0	139	86	0	0	0	0
JPN	53	31	49	25	0	0	0	0	0	0	46	36	0	0	0	0
MEA	589	2480	3736	2431	0	1236	2202	898	0	2187	957	976	0	1764	220	650
MEX	27	10	7	5	0	0	0	0	0	838	585	91	0	811	501	7
ODA	875	1485	1227	1205	0	0	0	0	0	0	334	228	0	0	0	0
SKO	102	14	41	25	0	0	0	0	0	0	23	25	0	0	0	0
USA	189	850	850	817	0	0	0	0	0	0	318	807	0	0	0	0
WEU	323	36	146	93	0	0	0	0	0	0	180	112	0	0	0	0

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